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DELIVERING NET ZERO

Review of Electricity Market Arrangements in the UK: Fundamental reform begins

The Review of Electricity Market Arrangements (REMA) consultation was published on 18 July 2022, but its unassuming launch belies its potential impact. REMA in fact kick-starts a multi-year process of review and potential reforms which may impact almost every electricity market segment - from generators, network operators, offtakers and consumers to traders and suppliers, as well as investors in market participants.

REMA aims to facilitate decarbonisation of the electricity sector by 2035

In order to reach net zero by 2050, the UK has committed to the full decarbonisation of the electricity sector by 2035. REMA's core objective is to reform electricity market arrangements to ensure that they facilitate the 2035 goal. The Department of Business, Energy and Industrial Strategy (BEIS) has identified five key challenges which need to be addressed to achieve the 2035 goal:

- increasing investment in low carbon generation capacity in order to meet decarbonisation targets;
- increasing system flexibility to support the balancing of supply and demand and the stability of the system as variable renewable generation increases;
- providing efficient locational signals to minimise system costs;
- maintaining system operability as variable renewable generation increases; and
- managing price volatility as variable renewable generation increases.

The current electricity market arrangements in Great Britain (GB) are unlikely to address these challenges. To date, policy has failed to deliver sufficient flexible assets to balance the increasing amount of intermittent renewable generation on the system. Electricity wholesale market pricing in GB means that the short-run marginal cost of the last generator to dispatch in any period sets the market price for all generators. In practice, gas-fired generators, with their high fuel costs, often set the price at times of peak demand (leading to calls during the current gas security of supply crisis for electricity prices to be decoupled from the gas price). However, in the longer term, as the amount of renewable generation increases, renewable plant with low operating costs will increasingly push flexible assets, with higher operating costs, out of the market. These flexible assets will need to recoup their costs within a smaller time period when renewable output is low, making new investment uncertain. At the same time, renewable generators will face lower market prices when renewable output is high. During periods when the wind is blowing and the sun is shining, their similar output patterns and low operating costs will increasingly drive down wholesale market prices, referred to as 'price cannibalisation'.

The start of a multi-year process

BEIS is seeking input from industry stakeholders on REMA's objectives for electricity market design and the case in favour of, and options for, reform. The current consultation will run until 10 October 2022, with a response anticipated in the winter.

The options under consideration in the REMA consultation span time frames from medium-term changes to existing arrangements that can be delivered from the mid-2020s to longer-term transformational reforms, as well as 'quick wins' which could be pursued on an accelerated timeline and implemented regardless of the end package of reforms.

Affecting almost all GB electricity market participants

REMA's aim is to deliver a net zero electricity wholesale market, mass low carbon power generation, flexibility, capacity adequacy and operability. REMA's scope is twofold:

- firstly, it considers electricity-related non-retail markets (including the electricity wholesale market, the Balancing Mechanism and the provision of ancillary services); and
- secondly, it considers technologies to the extent that they currently do, or potentially could, participate in electricity markets (including renewables, electricity storage, Demand Side Response (DSR), power generation with carbon capture and storage (CCUS), hydrogen-to-power, interconnectors and small modular nuclear reactors).

The participation of large-scale nuclear plants in electricity markets is also within REMA's scope, but investment mechanisms for these projects are not (for further information on the nuclear regulated asset base funding model, please see our briefing here).

A number of areas are excluded from REMA's scope, including support mechanisms to bring forward 'first-of-a-kind' technologies such as low carbon hydrogen production, dispatchable power agreements for power generation with CCUS and potential support for large-scale electricity storage and nuclear reactors. For further information on the hydrogen and CCUS business models, please see our dedicated website here.

Changes to the wholesale electricity market

BEIS is considering a number of options:

Splitting the wholesale electricity market into separate markets for variable and firm power

This would involve having a market for variable or 'as available' power and a market for firm or 'on demand' power. Prices in the variable market would be set on the basis of the long-run marginal cost of renewables (i.e. taking into account all the costs of producing a unit of energy, including production costs and any fixed costs such as building a new plant), whereas prices in the firm market would continue to be set by the short-run marginal cost (i.e. taking into account only the costs of producing an extra unit of energy, mainly fuel costs). The aim would be stable and predictable prices in both markets. In practice, most consumers would participate in both markets, but those consumers who could flex demand (e.g. by using an on-site battery) would be able to make savings by purchasing more of their electricity from the variable market. The intention would be to decouple prices in the variable market from gas prices and reduce volatility, thereby encouraging investment in renewable generation capacity and reducing costs for the engaged consumer. However, this option is largely theoretical and important questions remain to be answered. For instance: how prices will be formed in the variable market and how these two markets will interact, whether splitting the market will reduce liquidity and competition, and whether all of the variable power will be consumed before any firm power. A variation of this option would involve a pool for renewable power managed by the System Operator alongside the wholesale electricity market, with the System Operator purchasing power from renewable generators at their long-run marginal cost.

Introducing locational pricing, either zonal or nodal

This option looks to improve locational signals and encourage investment in generation where it is needed. The national price would be replaced with different prices depending on the zone or node. There is precedent for nodal pricing in the US, New Zealand and Singapore and for zonal pricing in the EU. Under nodal pricing, the price in each location reflects the locational value of electricity, taking into account the physical constraints of the network. Under zonal pricing, the network is divided into different zones, with the boundaries representing major network constraints. The intention would be to encourage more efficient use of the network and deployment of generation.

Distribution network level / local markets

This option has a number of design variations that involve establishing new local markets with distribution network operators (DNOs) or new service providers responsible for balancing a local market behind each grid supply point connecting the distribution networks to the national transmission network. The national wholesale electricity market would continue to operate (and be overseen by the System Operator), but it would be reconfigured to co-ordinate with these local markets (e.g. one option envisages service providers purchasing power from the national wholesale market to balance the local grid). A variation on this would see the introduction of locational imbalance pricing at each grid supply point. This would incentivise suppliers to source power locally and reduce network constraints. BEIS notes that the complexity of these distribution-led approaches may mean substantial delivery challenges but that they still warrant further investigation.

Pay-as-bid pricing as opposed to pay-as-clear pricing

The concern is that the wholesale electricity market currently results in all generators receiving the same price as the most expensive unit of generation procured during the relevant period. Exchanges operate on a 'pay-as-clear' basis and so the market price converges on this marginal price. In practice, this means that the price of gas generation (given that gas plants tend to be the marginal plant in GB) has effectively been setting the wholesale electricity price, even though this does not reflect the real cost of most generation on the system. An alternative approach being considered is 'pay-as-bid' pricing, where participants receive the price they bid/offer, but additional controls may be necessary to prevent strategic bidding. In practice, this would involve a higher degree of market intervention.

Incremental reforms

This option involves adjusting the parameters of the existing markets (e.g. changes to dispatch arrangements, changes to settlement periods and gate closure and changes to the Balancing Mechanism). The advantage of this approach is that it minimises disruption to the markets. For example, shortening the settlement periods would allow prices to respond more frequently to market conditions and would send appropriate signals to generators and demand-side response.

Mass low carbon power

The different approaches being considered by BEIS to support investment in low carbon generation capacity include:

Supplier obligation

This decentralised approach would oblige electricity suppliers to procure green electricity directly. The electricity suppliers would contract either directly with generators or through an intermediary, and would follow a trajectory set by the government for the maximum carbon intensity of electricity that can be sold to their customers. This trajectory would be aligned with achieving net zero. Key advantages associated with this market-driven approach include: (i) reducing the risk of inefficient government decisions about future capacity mix and maximising the potential for cross-technology competition; (ii) giving suppliers greater freedom; (iii) allowing suppliers to play a key part in decisions about capacity mix; (iv) incentivising smaller-scale and demand-side flexibility, electricity demand reduction and innovation; and (v) sending more effective locational signals through rewarding generation assets for building in locations best matched to the demand profile of electricity suppliers. However, there are issues such as counterparty risk when it comes to contracting with suppliers, and suppliers might not be best-placed to manage the investment needed to achieve net zero (particularly given the current challenges facing the retail market).

Building on the existing Contracts for Difference (CfD) scheme

BEIS is considering a number of options including: (i) a CfD with a strike range, with plants guaranteed a maximum and minimum price per MWh output and market exposure sitting within that range; and (ii) changes to the reference price methodology (e.g. CfD top-up payments could be set for a week, with opportunities for profit or loss if generators outperform the weekly average). Although BEIS does not comment on the implications for existing CfD contracts, as private law agreements, these may be varied only in accordance with their terms, subject to the application of usual principles of contract law.

Delivering system flexibility

Whilst a number of other interventions (such as locational pricing) may contribute to flexibility, the government is exploring options to deliver investment in new low carbon flexibility:

Revenue (cap and) floor

Assets such as flexible low carbon generation, storage, demand-side response and portfolios of decentralised assets (e.g. EVs or heat pumps) would compete for a government contract, guaranteeing a minimum revenue (a floor) to support investment via revenue certainty and possibly also setting a maximum revenue (a cap) to protect consumers from excessive profits. Key questions raised include how to design a fair and competitive market between flexible technologies and how to ensure assets remain sensitive to price signals once the cap is reached.

Reform of the capacity market (CM)

Options for reform include an optimised CM (see below) and new 'flexible auctions' which would procure specific flexible characteristics, such as response time and duration. Alternatively, multipliers might be added to the CM auction clearing price to reward valued flexibility characteristics, such as response time, location and duration. These measures would effectively counteract the de-rating factors that are applied to some technologies, such as long-duration electricity storage and interconnectors. However, BEIS notes that each intervention risks adding complexity to an already complex market and may not achieve the desired outcome if the parameters are not set appropriately.

Supplier obligation

This decentralised, market-led approach would place a legal requirement on electricity suppliers to procure flexibility or reduce demand during peak times, or to shift renewable generation to peak periods. This option carries a number of risks (e.g. counterparty risk and difficulty in visibility of performance in advance of peak periods).

Capacity adequacy

This is a reference to the need to secure investment in capacity to meet demand during peak times and maintain a certain level of security of supply. The CM was introduced in 2014 to support such investment. It allows thermal plants to recoup their costs, despite reduced operating hours due to the increase of renewable generation on the system. However, the CM does not currently provide sufficient incentives for flexible low carbon generation. The following options are highlighted by BEIS as front-runners:

Optimised CM

A number of options are under consideration, including separate CM auctions for new build or refurbished low carbon assets (which appears to be the front-running option) or allowing different clearing prices in the main market depending on capacity type (perhaps including a cap on low carbon asset bid prices). These options have been informed by the Capacity Market Call for Evidence (2021), with the government's response published alongside the consultation.

Strategic reserve

This would involve procurement by a central authority of a strategic reserve of capacity which would not participate in the main market and would be dispatched only when the main market does not clear (whether demand-side response can participate is an open question). This would act as a backstop mechanism to ensure security of supply.

Centralised reliability options

This would involve a central buyer procuring call option contracts, providing a right to be paid the difference between the real-time price and an agreed strike price at times of system scarcity from contracting assets, in return for paying the contracting assets a 'reliability premium' (usually determined by auction). The contracting assets effectively swap high wholesale market revenues at times of system scarcity for the strike price plus a capacity rent from the reliability premium. They are incentivised to be available because the difference payment is payable regardless of whether they are in fact generating. Reduction factors (similar to de-rating factors in the CM) would be applied and a penalty (or payback obligation) may apply in the event that the contracting assets do not meet availability. BEIS highlights the Capacity Remuneration Mechanism operating within the Integrated Single Electricity Market on the island of Ireland as an example of this model.

The other options being considered by BEIS (though not as lead options) include decentralised reliability options or obligation models for electricity suppliers, a market-wide capacity payment and a targeted tender/capacity payment (awarded by auction).

Operability

BEIS also proposes to review the ancillary services market (i.e. services such as frequency control, black start or inertia procured by the System Operator to keep the electricity system in balance in real time).

This has been subject to reform since the System Operator proposed its System Needs and Product Strategy in 2017, and further changes are an important aspect of the 2021 Smart Systems and Flexibility Plan. However, BEIS notes that further changes are needed, as most ancillary services are provided by thermal generators that will need to be replaced by low carbon alternatives in order to achieve the 2035 commitment. The extent to which variable renewable generators would be able to provide services such as reserve (which relies on firmness of supply) and the role of DNOs in managing local networks are open questions.

BEIS identifies that continuing the implementation of the System Operator's Markets Roadmap (March 2022) may be a viable option. The other front running-options identified in the REMA consultation are:

Enhancing existing policy

BEIS notes that enhancements might include providing the System Operator or Future System Operator with the ability (or obligation) to prioritise zero/low carbon procurement. This would go beyond the statutory duties already proposed for the Future System Operator to promote this alongside maintaining security of supply and ensuring an efficient, coordinated and economical system. Another option is to ensure that the System Operator strikes the right balance between short and longer-term contracts, recognising the value of the latter in bringing forward investment. This is likely to be welcomed by many market participants.

Developing local ancillary services markets

With more distributed generation and electrification of transport and heating, the REMA consultation encourages respondents to consider if there may be a need for more active network operation management by DNOs. This is also under consideration as part of Ofgem's Call for Input: Future of local energy institutions and governance (April 2022).

Changes to the CfD or changes to the CM

BEIS is considering two options. The first entails changes to the CfD to incentivise generators with CfDs to offer ancillary services. These generators are currently reported to be disincentivised to do so, as they would need to bid high prices to recover the subsidy lost from diverting power from the wholesale market. The second option looks at changes to the CM to include obligations or incentives to provide ancillary services.

Co-optimisation of the wholesale market

This option is being considered together with broader wholesale market changes, such as nodal pricing, that would involve central dispatch by the System Operator. In a system with central dispatch, ancillary services can be co-optimised when sending dispatch signals. This approach is reported to be used in the US market for frequency and reserve, but other ancillary services are still provided by long-term contracts to underpin investment.

Options across multiple market elements

BEIS is also considering two options which cover multiple elements of market design at once. These are:

Auction by cost of carbon abatement

This option explores adapting the Dutch SDE++ support scheme, and proposes paying technologies, including generation, flexibility and demand reduction, the difference between a base tariff awarded per tonne of CO2 abated and an estimated market price. BEIS notes that this would not be appropriate for flexible assets which need to generate or reduce demand when there is a deficit of low carbon generation, and require signals to increase demand when there is an excess of renewable generation. This option also relies on the ability to calculate accurately carbon abatement. BEIS is not minded to pursue this option for mass low carbon power as the SDE++ is a one way CfD and so it is unlikely to provide value for money compared to the existing CfD for renewables.

Equivalent firm power auction

Originally proposed by Professor Dieter Helm in the Cost of Energy Review (2017), this option creates a single unified auction by a central body for procuring system capacity. Renewables are encouraged to internalise the cost of their variability and to contract with flexible assets due to the application of: (i) de-rating factors based on the quantity of firm capacity required to offer the same level of security of supply during periods of scarcity; and (ii) penalties for non-delivery. A carbon constraint could be added to ensure the auction results meet emissions targets. BEIS notes a number of potential drawbacks to this model, including the increased risk for renewable investors.

Consideration of contractual implications is needed

Whilst many recognise that reform is needed, a number of the options being considered would represent a fundamental redesign of existing electricity market arrangements and would have significant consequences for power trading practices and bilateral sales, as well as for those accessing existing support schemes such as CfDs. Careful consideration will be required to ensure appropriate implementation.

Potential impact on electricity sales

There will be knock-on consequences for trading arrangements and REMA could have wide-reaching implications in relation to power purchase agreements (PPAs), not just for generators but also for counterparties to a PPA or other long-term contract which uses a reference price linked to the wholesale electricity market.

The implications of the proposed changes will need to be considered in the context of each market participant's particular business and circumstances. In the case of proposals to introduce different markets for variable and firm power, for example, key questions include how the reforms will impact the economics of the generator and offtaker and how the existing contracts will respond (e.g. change in law or replacement reference price provisions). A generator with project finance in place will also need to consider the implications of changes to pricing under its offtake arrangements for its financing. Offtakers and their trading desks will need to consider how changes impact their wider trading strategy.

The options being considered by BEIS are at an early stage and it is not clear at this point what changes will be made to existing electricity market arrangements. However, market participants will want to begin considering what steps they might take to pre-empt issues that could arise under their contracts. In practice, parties looking to enter into a long-term contract linked to the wholesale electricity market will want to consider potential implications for the contract, how provisions such as change in law, pricing and termination might operate, and what knock-on consequences could arise under related financing arrangements.

Impact on CfDs for renewables

The reference price, which is integral to the difference payment under the CfD, is calculated by reference to market indices and so any change to the electricity wholesale market is likely to impact its calculation. The CfD Standard Terms include (in Annexes 4 and 5) a mechanism to review the baseload or intermittent reference price (as applicable) upon the occurrence of a trigger. The implementation of certain options being considered in REMA is likely to trigger this mechanic and, indeed, a split in the GB electricity market is already expressly included as a trigger (this was introduced as a result of zonal pricing within the EU's Internal Energy Market). Generators will be considering the amendment mechanics closely. They will also want to consider whether the implementation of any options following REMA might also constitute a qualifying change in law. However, the operation of change in law provisions under the CfD can be a complex process and whether they are engaged will again depend on the nature of the change.

Options require careful assessment

Increased involvement from the System Operator and DNOs

A number of the options being considered would involve more active management by the System Operator and DNOs (e.g. local markets being run by the DNOs and central dispatch by the System Operator). There are advantages associated with central dispatch (e.g. taking a market-wide view and accounting for factors such as congestion and balancing). However, careful design and governance arrangements are required to guard against gaming by participants and to ensure efficient operation by the System Operator. A centralised model and increased intervention in order to achieve objectives may look good in theory, but there is a question as to whether this will operate efficiently in practice and deliver what is envisaged.

Impact on renewable generation

Investment has flowed into asset classes such as offshore wind in part due to the UK's stable regulatory framework and the grandfathering principles applied to support regimes. It will be vital to maintain the confidence of investors in renewable generation throughout the REMA process, both in relation to existing assets and future investment opportunities.

Locational pricing may represent a particular challenge – renewable generation is often located in remote areas due to planning constraints or renewable resource availability. In practice, this limits the ability of developers to bring forward projects near centres of demand and means that projects are often situated behind grid bottlenecks. Variable renewable projects also tend to involve high upfront capital expenditure and lower operating costs, so they are often referred to as 'price takers' which dispatch even at low prices in order to recoup value. This means that they are likely to be impacted by the introduction of nodal pricing – even prior to the publication of REMA, in response to National Grid's Net Zero Market Reform Phase 3 assessment (May 2022), RenewableUK in a blog post published in May 2022 urged caution in relation to the adoption of nodal pricing, emphasising the need to consider investor sentiment.

Conclusions

REMA begins a long-awaited and necessary conversation regarding the fitness for purpose of electricity markets to deliver net zero. However, change often entails value reallocation. It will be important to maintain investor confidence throughout the REMA process in order to ensure that the investment needed in the GB power market continues at pace in the coming decade.

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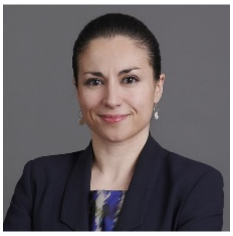

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